AG-2-5 (Att. 2)

Case No.________

ROCHESTER GAS AND ELECTRIC CORPORATION

DIRECT TESTIMONY OF

HETHIE S. PARMESANO

NATIONAL ECONOMIC RESEARCH ASSOCIATES

February, 2002

Q. Please state your name and business address.

A. My name is Hethie S. Parmesano. I am a Vice President at National Economic Research Associates, Inc. at 777 South Figueroa Street, Suite 4200, Los Angeles, CA 90017.

Q. On whose behalf are you appearing?

A. I am appearing as an expert witness on electricity marginal costing and tariffs on behalf of Rochester Gas & Electric Corporation.

Q. What is the purpose of your testimony?

A. I will (1) define marginal cost principles and explain why they are the appropriate basis for electric utility rate design; (2) describe the history of marginal cost-based rates in New York State; and (3) describe the development of the gas and electric marginal costs being used by RG&E in this case.

Q. What are your qualifications as an expert witness on these issues?

A. I received a B.A. degree in economics from Colby College and M.A. and Ph.D. degrees in economics from Cornell University. I have worked as a utility economist/consultant since 1977, first at the Los Angeles Department of Water and Power and, since 1980, at National Economic Research Associates, Inc. (NERA), a firm of consulting economists with offices in 9 US cities as well as Brussels, Rome, London, Madrid and Sydney. At NERA I have concentrated on marginal costing, marginal cost pricing, regulatory reform and strategic planning, largely for gas and electric utilities and regulatory commissions. I have done some work on marginal costing and rate design for water utilities as well.

Each year since 1981 I have taught annual (or more frequent) seminars in both marginal costing and marginal cost pricing. Attendees include staffs of utilities and regulatory commissions, as well as occasional commissioners. I also participate regularly in the University of Florida's training sessions for utilities and regulators around the world, presenting the sessions on electricity tariff design.

I direct NERA's Marginal Cost Working Group (MCWG), a group consisting of representatives from North American gas and electric utilities (including RG&E). The MCWG, in existence since 1982, is dedicated to advancing the state-of-the-art of estimating and applying marginal costs. I have been involved in planning for and implementation of retail access in many jurisdictions around the world, including California, New York, Ohio, New Mexico, Maine, Illinois, Maryland, Arizona, Oregon, India, Brazil, Argentina, El Salvador, Mexico, Spain, Greece, Ireland, and the UK. A detailed resume is attached as Exhibit 36, Schedule A.

Q. Please summarize your testimony.

A. As the Commission has long recognized, electric and gas rates that are based on marginal costs:

provide price signals that encourage efficient consumption and investment decisions by consumers, lead to consumption patterns and levels that allow the utility and other market participants to invest in only the amount of capacity consumers are willing to pay for and to make good use of the capacity that is available; promote effective competition (1) with other types of energy, (2) with energy-saving equipment, (3) with other regions and countries, and (4) among competing suppliers of newly deregulated components of electricity and gas service.

It is particularly important, as New York phases in retail access, for customers taking service from the utilities to face prices for competitive service elements that neither overstate nor understate the utilities' marginal costs of providing them. If utility prices for these elements are above marginal cost, inefficient competitors will enter the market and total costs of the sector will be higher than necessary. If utility prices for these elements are below marginal cost, efficient new entrants will be excluded, which will also result in higher costs than necessary for the sector.

Marginal cost-based electric and gas rates are equitable. They ensure that customers increasing their consumption pay the additional costs, so that no other consumer (or shareholder) is required to provide a subsidy, and that growing customers do not have to subsidize customers whose demands remain unchanged.

Marginal cost prices also make good business sense for the utility. If rates are structured so that charges on consumption reflect marginal costs and non-marginal costs are recovered in changes that do not vary with consumption, the utility is protected from unexpected changes in kWh or therm sales. This reduces the risk for the utility and helps keep down the cost of capital and total revenue requirement. This feature of marginal cost pricing is particularly important for delivery companies, whose costs are largely fixed relative to kWh or therm sales.

Marginal cost pricing involves compromises to achieve all of the utility and regulator's ratemaking objectives, including revenue adequacy and avoidance of unacceptable bill impacts. However, qualitative use of the inverse elasticity principle (explained in more detail below) can help insure that any distortions in the efficiency of the final rates are minimized.

The methods we used to estimate RG&E's marginal costs of electric and gas service are updated version of the methods used by RG&E in the past and, for the most part, familiar to the parties in this case. There are some changes, however.

The biggest changes are the use of market price estimates for generation and transmission (for electricity) and commodity (for gas). The generation and transmission elements of electric marginal cost are incurred on a per-kWh basis, implying a heavier emphasis on energy charges in an efficient rate design than is the case when these costs are incurred on a peak demand basis.

We applied the same approach to distribution marginal costs used in RG&E's past electric studies to the gas study. Local gas distribution facilities are sized on the basis of design demand (not actual peak day demand or gas consumption) and it is appropriate to compute (and charge for) the marginal cost of these components of the gas system on the basis of the design demand for a particular customer type. This change implies higher fixed monthly gas charges than suggested by previous studies.

Our computation of most marginal non-plant-related A&G and general plant expenses is based on regression analyses, which give true marginal estimates of these loads, rather than the historical averages used in the past.

Q. What are marginal costs?

A. Marginal cost is the additional cost incurred to provide a small increment of a good or service, or the savings from a small decrement. It is a forward-looking concept that ignores sunk costs and asks the question: how would costs change if there were a hypothetical small change in output.

Q. What are the elements of the marginal cost of *electricity* service?

A. Electricity service is complex and there are several elements of the marginal cost of providing it. First, there are costs that are marginal with the number of customers on the system. These costs include the meter and service drop used by the customer, as well as customer-related expenses such as meter-reading, billing, accounting, and customer service. Second, there are the costs that are marginal with respect to the design demand of the customer. When the local distribution system is laid out, the engineers make assumptions about the likely appliance stock and usage of the premises and size of the secondary and primary lines and transformer needed to accommodate the demands by customers at that location for many years to come. Once these facilities are in place, unless there is a dramatic change in the customer's load (triggering a new design demand estimate), there is no local distribution marginal cost associated with changes in monthly energy consumption or monthly peak demands. These costs are marginal when the initial equipment in installed and whenever it is necessary to replace it, although the costs are typically recovered through monthly charges rather than upfront at the time of installation. Third, there are marginal costs associated with the distribution system farther upstream. Trunkline primary feeders and distribution substations are shared by many consumers. The capacity of this part of the distribution system is adjusted with changes in demand from year to year. Thus these marginal cost elements do vary with usage in the hours when reserves on these facilities are tight. Forth, marginal use of the NYISO-controlled transmission system triggers a transmission service charge (TSC) set by FERC. This charge is the marginal cost of transmission to RG&E. Finally, the marginal cost of generation is the market price of energy and capacity within RG&E's control area.

Q. What are the elements of the marginal cost of *gas* service?

A. The elements of gas marginal costs parallel those of electric service. There are customer-related costs (meter, regulator, relief value, service lateral, and associated expenses), local low- and medium-pressure distribution costs (mains and regulator stations) related to maximum customer requirements, transmission mains and high-pressure distribution mains and regulator station costs related to peak day usage, and delivered commodity costs.

Q. What are the arguments for basing electric and gas rates on marginal cost?

A. There are three major arguments, based on economic theory, for using marginal costs in setting electric and gas rates. The first is that consumers will make efficient consumption choices when the price they face reflects the underlying economic costs of using a little more or a little less. The second is that efficient investment by electricity suppliers is encouraged when consumers make efficient consumption decisions. The third is that marginal cost pricing promotes effective competition. There is also an equity argument for marginal cost pricing, and a business reason.

Q. How does marginal cost pricing promote efficient consumption decisions?

A. Economists agree that marginal cost pricing results in an efficient allocation of resources. Briefly, the theoretical argument is: Marginal cost is the cost of the resources needed to produce the next or last small increment of output. It represents the value of those resources in their next best alternative use. Price represents the personal value, to the consumer, of the next or last small unit consumed. It is an indication of the amount of alternative consumption willingly foregone to consume the unit in question.

When prices equal marginal cost, the production cost of the next or last unit exactly matches the value of that unit to the consumer and resource allocation is socially optimal. The resources used to produce the unit cannot be used for another purpose and produce greater consumer satisfaction. If price is below marginal cost, consumers will continue to buy additional units when the satisfaction they receive is below the cost of supplying the additional units. Resources are used up that would have produced greater satisfaction if used to produce something else. If price is above marginal cost, consumers artificially constrain their use of the good or service. Benefits they would have enjoyed from consuming more, at a resource cost lower than the value of those benefits, are foregone.

The provision of accurate economic signals to consumers requires taking marginal costs into consideration. Rates that reflect the marginal cost of service signal to consumers the cost of their consumption decisions. A consumer deciding what type of appliance to buy or how much to use existing energy-using equipment will make socially efficient choices if the price for the additional (or saved) unit of gas or electricity is equal to the cost of supplying it. In this case consumers have the incentive to make efficient energy choices because of what they pay or save as a result of those choices.

Q. How does marginal cost pricing promote efficient system expansion?

A. As I explained above, marginal cost pricing promotes efficient *consumption* decisions. Because system expansion and operation are determined by consumption, economically inefficient prices lead to unnecessary investment in new energy supply and delivery facilities or poor utilization of existing facilities; efficient *consumption* is a prerequisite for efficient *system expansion*.

Peak-load pricing provides a good illustration of how failure to use marginal cost pricing leads to inefficient system design. If peak period use has a higher marginal cost than off-peak use, but prices are not time-differentiated, consumers will use more than the optimal amount in the peak period and less than the optimal amount in the off-peak period. As a result, the utility (or other investors) will install more total capacity than optimal, and will have more than optimal idle plant in off-peak hours. The result is higher than necessary total costs. Some customers may even be driven by these high costs to install their own generation, resulting in uneconomic bypass of the utility's system and further wasted resources.

Q. How does marginal cost pricing promote effective competition?

A. RG&E faces competition for its electricity and gas services from other regions (particularly for business and manufacturing customers), from other types of energy (including oil, propane, and self-generation), and from goods and services that reduce gas and electricity consumption (for example, insulation, load management controls, more efficient lights and motors). In each of these examples, RG&E is competing with other firms, most of whom are not regulated and will enter or leave the market based on their profitability. If RG&E prices the loads for which these firms are competing below the real (marginal) cost of providing that service, RG&E may drive what would otherwise be successful, efficient competitors out of the market. If RG&E prices the loads for which these firms are competing above the real (marginal) cost of providing that service, RG&E will make it possible for inefficient firms to enter the market. Thus, marginal cost pricing by regulated suppliers helps minimize distortions in the competitive market and thereby improves the efficiency of the energy industry as a whole.

Q. How is marginal cost pricing equitable?

A. Marginal cost pricing is equitable because every consumer pays the costs of supplying his/her requirements at the margin. If the customer consumes more – no one else provides or receives a subsidy. If the customer consumers less – his/her bill goes down by the amount of the costs saved. Again, no one else's bill is affected.

Q. How can marginal costs be used to design electric and gas rates in the case where there is a revenue constraint; i.e., if charging marginal costs as prices would not produce the authorized amount of revenue and there is a marginal cost revenue gap?

A. When charging marginal costs as rates would produce too little revenue, some charges must be increased. To maintain as much of the efficiency and equity benefits of marginal cost pricing as possible, charges that are collected on the basis of usage should be set at or near marginal cost and other costs recovered in fixed elements of the rate structure. The reverse is also true; fixed charges should be adjusted downward if marginal cost pricing would produce too much revenue. Of course it is also important to keep in mind total bills when making these adjustments up or down. For example, if raising fixed charges sufficiently to cover the revenue gap would make self-generation cost effective, even though the cost of self-generation exceeds the utility's marginal cost, some other gap-closing mechanism must be used. In addition, a one-time shift to marginal cost pricing might cause unacceptably high bill increases for some customers, necessitating a gradual adjustment or other transition mechanism.

Q. What is the business reason for marginal cost pricing that you referred to earlier?

A. A regulated utility, unlike a competitive firm, is not permitted to change its prices whenever it likes. Instead, there are rules about how often prices can be changed and even then a lengthy regulatory procedure must be followed before changes can be implemented. If regulated rates are structured so that the charges per kWh or per therm recover more than the costs that are variable with respect to kWh or therm use, the utility runs the risk of a revenue shortfall in the event that electricity or gas sales are lower than expected; the loss of revenue will exceed the reduction in costs. Setting prices for the variable component of rates close to marginal cost helps to control this risk. In today's environment where rates are typically set through negotiated agreements which establish rates for 3 to 5 years or more, this is more important than ever.

This problem is particularly severe for delivery charges to customers who purchase their gas or electricity from another supplier. The utility providing delivery service faces costs that are largely fixed with respect to the amount of energy or gas delivered. Thus the financial condition of the entire delivery company is at risk if delivery rates are levied primarily on the basis of gas or energy consumption. An extreme example of this problem is the situation faced recently by distribution companies in Brazil. Government-mandated power rationing (necessitated by severe energy shortages) significantly affected their net revenues. Customers were required to reduce their consumption 15, 20 or 25 percent (depending on type of customer) below their average level the previous year, with a penalty of a three-day power cut for the second infraction and a six-day cut for the third.

Q. What are the steps in developing a marginal-cost based rate design?

A. There are eight main steps in the process of using marginal costs as the basis for electric or gas rate design.

The first step is to define the objectives the new rates are designed to accomplish. Typically these objectives include revenue adequacy and certainty, efficiency, equity, and administrative feasibility, but may also include a smooth transition to retail access and solving specific problems with current rates.

The second step is to compute detailed marginal costs for each customer class, reflecting costs by time-of-use and looking out several years into the future, if possible. Where costs vary significantly within current classes, it may be appropriate to increase the number of classes or create sub-classes. It may also be appropriate to consolidate classes if the marginal costs are similar.

The third step is to compute total marginal cost revenues by multiplying the detailed marginal costs by the appropriate measures of usage and size for each class and summing over all classes.

The fourth step is to compare total marginal cost revenues to the revenue requirement to quantify the marginal cost revenue gap.

The fifth step is to determine revenue allocation by customer class. Each class should pay rates that produce sufficient revenues to cover the class' marginal cost revenues (assuming marginal cost revenues are lower than the total revenue requirement). The gap should then be allocated to classes in a way that produces the least distortion to consumption, compared to pure marginal cost pricing (which ignores any revenue gap). If the gap is fairly small and can be added to monthly fixed charges without creating unacceptable bill impacts (or uneconomic bypass), the gap can be spread to classes using the EPMC (equi-proportional marginal cost) rule. Each class would be assigned a share of the gap proportional to its share of marginal cost revenues. If the gap is too large for this approach and information is available about the relative price-sensitivities of the various customer classes, a version of the "inverse-elasticity" rule can be used. This rule helps determine which variable components of which rates should be adjusted upwards to help close the gap. If reliable information about relative elasticities is not available, the EPMC approach can be applied, with the portion of the needed mark-ups that cannot reasonably be included in fixed charges applied to variable charges.

Q. What is the "inverse-elasticity rule"?

A. The basic idea behind the inverse elasticity rule is that consumers who are not very price-responsive will not change their consumption much, even if they face prices for marginal use that exceed marginal cost, whereas customers who are price-responsive will. So the customers with elastic demands should have a smaller amount added to their per-kWh or per-therm charges than inelastic customers. The mathematical formulas for making these adjustments are very complicated and require detailed information about price responsiveness at different times, to different rate elements, and to different price increments—all of which are rarely available. However, the rule can be used *qualitatively* even without all this detailed information. For example, if large customers have the ability to shift production to a factory in another region or heating customers will switch types of space heating if the price per unit of gas or electricity gets beyond a certain level, these facts should limit the adjustments being made.

Q. What are the next steps in the rate design process?

A. The sixth step is to define the rate structure and levels of each rate element for each class. Ideally the rate structure for each class should follow the structure of marginal cost. This implies a fixed monthly charge to cover marginal customer costs, a charge per kW of design demand (or peak gas delivery capability requirement) to cover local delivery costs, and time-differentiated charges to cover the additional delivery and commodity costs. It may be possible to combine the customer and local facilities charges. It may be necessary to use different diurnal pricing periods for the various classes of electric customers (and no time-of-use differentiation within a season for small customers without TOU metering). It may be appropriate to use a combination of demand and energy charges for larger customers. And blocking may be the best way to help close the revenue gap without distorting prices for marginal consumption. Once the appropriate structure for each class is determined, the marginal costs (properly averaged, if necessary) plus the revenue gap amounts determined in the previous step are used to set the levels for each rate component.

The seventh step is to evaluate the bill impacts of the preliminary proposal and determine whether the objectives identified in Step 1 have been achieved. This is accomplished by reviewing the effect on bills of typical customers of various sizes in each class.

The eighth step is to refine the proposal to minimize unacceptable bill impacts and improve achievement of the objectives.

Q. Has the marginal cost philosophy of rate design been used in New York State in the past?

A. Yes. In fact, marginal cost-based rate design is the accepted norm in New York. New York was one of the first states to endorse marginal cost principles for utility rates. Beginning with its August 10, 1976 Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures in the "Generic Electric Rate Design" case (Case 26806, Proceeding on Motion of the Commission as to the Rate Design for Electric Corporations, 16 NYPSC 671), the Commission has continued to moved forward with marginal cost pricing for electric service. In addition, the Commission, in its September 17, 1979 Opinion and Order Determining the Relevance of Marginal Costs to the Regulation of Gas Distribution Companies in the "Long-Range Gas Planning" case (Case 26835, Proceeding on Motion of the Commission as to the Long-

Range Plans of New York State's Gas Distribution Companies), determined that marginal cost concepts are properly applicable to gas service. In subsequent decisions and pronouncements, the Commission has continued to move electric and gas pricing toward more complete implementation of marginal cost principles.

Q. What indication is there that the Commission continues to support implementation of these principles, particularly in the case of RG&E?

A. With regard to electric cost allocation and rate design, the Commission, in its last rate decision prior to the adoption of the settlement in RG&E's "Electric Restructuring Case" (Case 96-E-0898, In the Matter of Rochester Gas and Electric Corporation's Plans for Electric Rate/ Restructuring Pursuant to Opinion No. 96-12), made clear that, "as the company moves to a more competitive environment, the cornerstone of electric rate designs will be to approximate marginal cost in pricing" (Cases 95-E-0673 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service, Opinion and Order Concerning Revenue Requirement and Rate Design, issued September 26, 1996, p. 23). The Commission went on to say: "Marginal cost-based pricing rests on the sound economic principle that efficient resource allocation is enhanced by pricing goods and services as closely as reasonably achievable to marginal costs. It has been our long-standing policy to price electricity such that consumers pay for the cost their consumption imposes on the utility so that scarce resources are efficiently allocated" (id. at 23-24).

In a decision approving RG&E's most recent gas settlement, the Commission reiterated its reliance on marginal cost principles – specifically RG&E's most recent marginal cost study – in rejecting claims that a proposed increase in the minimum customer charge was excessive (Case 98-G-1589, In the Matter of Rochester Gas and Electric Corporation's Plans for Gas Rates and Restructuring, Order Adopting Terms of Joint Proposal, issued February 28, 2001, p. 14). (Although the Commission modified the marginal cost-justified minimum charge in one respect, by freezing the charge at its current level for certain low-income, low-usage customers, this change did not call into question the overall desirability of moving the minimum charge closer to the demonstrated marginal cost of service.)

Accordingly, the use of the marginal cost philosophy of rate design in New York, and particularly with respect to RG&E's rates, is well established and fully supported by the Commission.

Q. Please describe the methods you used to compute estimates of RG&E marginal costs of electricity service.

A. Our basic approach was to determine the response of RG&E's planners and system operators to changes in the number and size of customers and their energy consumption at various times of the day and year.

- Generation -- In a competitive market such as New York's, the marginal cost of generation – both energy and capacity – is the market price. Thus we based our marginal energy cost estimates on forecasts of hourly energy spot prices for the NYISO Zone B. Similarly, our estimate of the marginal cost of generation capacity is the annual market price per kW of capacity at Genesee, times the installed capacity (ICAP) requirement factor applicable in RG&E's transmission district (1.175). This marginal annual cost is incurred only if load grows at the time of RG&E's system peak; therefore, we assigned the annual cost to hours of the year on the basis of their relative probability of being the peak hour of the year.
- Transmission -- If customers in RG&E's territory use more energy, the ESCO serving those customers must incur RG&E's transmission service charge (TSC) for transmission of the additional energy across the NYISO-controlled transmission network. These charges are set to cover each transmission owner's transmission revenue requirement. When RG&E is the ESCO serving the customer, the utility essentially pays the TSC to itself. Thus, the TSC is RG&E's marginal transmission cost.
- Distribution substations and trunkline feeders -- We estimated the marginal cost of these distribution elements by dividing the budgeted growth-related investment by additions to capacity (adjusted the result for reserves typically built into such facilities). The marginal investment was annualized using an

economic carrying charge and the annual costs adjusted for O&M, A&G, general plant, and working capital. We time-differentiated the annual costs using estimates of distribution probability of peak.

- Local distribution facilities – Secondary lines, transformers, and local primary lines are sized on the basis of design demand and are marginal only when service is extended to a new area or the facilities have to be replaced. We estimated these costs by updating an earlier RG&E study that computed distribution facilities costs for typical-sized customers in each class. These costs were annualized using the same procedures described for distribution substations.
- Meter and service drop – RG&E provided the cost of a typical meter and service for each class. We applied carrying charges, O&M estimates, and loaders for overheads.
- Lighting costs – For lighting classes for which RG&E provides the lighting equipment (lamps, brackets and facilities), RG&E supplied current unit costs and O&M estimates. We computed economic carrying charges and loaders to be applied to these estimates.
- O&M expenses -- We estimated marginal O&M expenses of various types by analyzing average levels of O&M expenses in the past few years, and using trends over that period to predict marginal levels of these costs in the future.

Each of the usage-related marginal costs was adjusted for losses to account for the effect of demand increases by customers at each voltage level of service. A detailed description of the methods used is contained in Exhibit 36, Schedule B.

Q. How are these methods different from the methods used by RG&E in its last electric marginal cost study, prepared in 1995 and filed with the Commission in Docket No. 95-E-0673?

A. The biggest difference is the use of market prices for generation energy and capacity costs, and the use of the TSC as RG&E's marginal transmission cost. The new structure of the electric industry in New York State requires these changes, since changes in demand by RG&E's electric customers trigger market transactions, not a different dispatch of RG&E's generation. The energy and transmission costs are incurred on a per kWh basis. The capacity costs are expressed per kW, but since they can be incurred on an expected basis in many hours of the year, it makes sense to unitize them on the basis of energy. Because all three of these marginal costs are stated on a per-kWh basis, the marginal cost results imply a heavier emphasis on per-kWh charges than past studies.

Another change is the use of the budget for distribution substation and trunkline feeder projects as the basis for this element of marginal cost. RG&E's last study used the estimated distribution facilities costs times the number of customers expected to be added to the system in the budget period as a deduction from the total distribution budget, and then used the residual as the basis for the remainder of the demand-related distribution marginal costs. We believe that identifying the specific growth-related projects involving distribution substations and trunkline feeders is a more accurate way to estimate this element of marginal cost.

We used regression analysis to develop estimates of marginal loaders for non-plant-related A&G expense and general plant. The coefficient of the regression equation gives a truly marginal loader, which is more appropriate than the older approach used by RG&E and many other utilities, which uses the simple average historical relationship between aggregations of A&G accounts (or general plant) and total expenses or total plant. The loader for the only account determined to be plant-related, property insurance, was developed from expected insurance rates.

RG&E's last electric marginal cost study used a complex model that required as inputs estimated hourly loads at each system level to compute marginal losses. For this study we used a simpler computational approach that did not require (unavailable) hourly loads at each level.

Q. Please describe the methods you used to compute estimates of RG&E's marginal costs of gas service.

A. Like our electric marginal costing approach, our gas methods are based on the system planning process. We analyze what drives new investment and purchase decisions and how changes in consumption affect system operations.

- Commodity costs – In a competitive gas market, the short-run marginal cost of gas commodity is the spot market price of gas (delivered to the city gate), adjusted for losses and cash working capital. We relied upon a forecast of monthly gas market prices provided by RG&E to develop this element of the marginal cost.
- Transmission costs – RG&E does not have plans for significant new transmission (mains operating at above 124 psi). Therefore, we used the cost of a project being contemplated, and divided the cost by the additional capacity it will provide, adjusted for a reserve margin. This marginal investment was annualized using an economic carrying charge and adjusted for O&M, A&G, general plant and working capital requirements. The annual costs were assigned to months on the basis of probability of peak day.
- High-pressure distribution facilities – For high-pressure regulator stations, we used the cost of a typical station, divided by its capacity and adjusted for a reserve margin. We used the budget for growth-related high-pressure mains as the basis for this element of marginal cost, dividing investment by increased capacity, again adjusted for a reserve margin. Both of these elements of high-pressure distribution cost were annualized and time-differentiated using the same procedures as for transmission.
- Local distribution facilities – The medium and low-pressure portions of the distribution system are designed using engineering standards that take into

consideration the expected long-term maximum demands of customers that will use them. These costs are marginal when the mains are installed and if they are ever replaced, but do not vary with the customer's actual demands from month to month or year to year. Therefore, the marginal cost of these facilities should be computed (and recovered) on the basis of design demands, not per customer or per therm consumed. We estimated the cost of medium-pressure regulator stations using the cost per MCF/day of a typical station, adjusting for the estimated ratio of regulator capacity to design demand. We estimated the cost of medium and low-pressure mains by taking the total value of existing facilities (in today's dollars) on RG&E's system and dividing by estimated total design demand. These estimated marginal investments were annualized and adjusted as for the other types of marginal investment described above. These costs are not time-differentiated.

- Customer-related facilities – Each customer uses a meter, house regulator, relief value and service lateral. RG&E provided estimates of the typical installed cost of these facilities for each customer class. We annualized and adjusted them as described for other types of marginal investment. These costs are not time-differentiated.
- O&M – We estimated marginal levels of each type of O&M by analyzing the level of these expenses in the recent past, and discussing with RG&E the level likely to be representative of marginal expenses in the near future.

Marginal costs were converted to costs at customers' meters by applying a loss factor. A complete description of the methods used in the gas study is contained in Exhibit 36, Schedule C.

Q. How are these methods different from the methods used by RG&E in its last gas marginal cost study, prepared in 1995 and filed with the Commission in Docket No. 95-G-0674.

A. One major difference between the new and former gas study is that the new study includes an estimate of marginal commodity costs, whereas the older study covered only delivery costs.

The second major difference is that the new gas study uses the same philosophy followed for years in RG&E's electric marginal cost studies to define local facilities costs in terms of design demand, rather than peak day use. We believe that this approach is consistent with RG&E's system planning criteria and gives a better basis for efficient prices than the old approach, which treated all distribution facilities costs above the cost of mains installed to serve residential heating customers as related to consumption, rather than design demand.

Several elements of the gas delivery system were analyzed using typical installations rather than the budget for such facilities, because there is so little near-term growth forecast that RG&E is not planning expansion of all elements of the system.

We used in the gas study the new regression approach for A&G and general plant loaders described for the electric study.

Q. If RG&E's marginal cost revenues were equal to the revenue requirement approved by the Commission, for both gas and electricity, what would efficient prices look like?

A. If RG&E were to keep its current rate structures for gas and electricity prices, but apply the seasonal differences revealed by the marginal cost analysis, the marginal gas costs we developed could be converted directly to rates by averaging the monthly costs across the months in each season. These are shown in the Schedules 30-32 of Exhibit 36, Schedule C. Conversion of the electric marginal cost to rates using current electric rate structures, but with seasonal price differences for all classes, would require averaging costs across diurnal periods for customers without time-of-use meters. These are shown in the Schedule 29 of Exhibit 36, Schedule B.

Not all of RG&E's current rate schedules include seasonal differences. If the current degree of seasonality were preserved, the efficient prices would be as shown on Schedules 33-35 of Exhibit 36, Schedule C for gas and Schedule 30 of Exhibit 36, Schedule B for electric.

Q. Does this conclude your testimony?

A. Yes, it does.